IDAHO POWER
An IDACORP Company

BARTON L. KLINE
Senior Attorney

August 7, 2001

Ms. Jean D. Jewell, Secretary
Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-01-16
Rebuttal Testimony

Dear Ms. Jewell:

Please find enclosed for filing nine (9) copies of the Company's rebuttal testimony and exhibits of Witnesses Simard and Gale. Copies of this filing have been hand-delivered, mailed, or sent by overnight mail to the parties as indicated in the enclosed Certificate of Service.

Also enclosed is a computer disk for the court reporter containing the testimony of the witnesses. We will send you an e-mail containing all of the documents involved in this filing.

I would appreciate it if you would return a stamped copy of this transmittal letter for our file.

Very truly yours,

Barton L. Kline

BLK:jb
Enclosures

Telephone (208) 388-2682, Fax (208) 388-6936, E-mail BKline@idahopower.com

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 7th day of August, 2001, true and correct copies of the TESTIMONY AND EXHIBITS OF WITNESSES SIMARD and GALE in Case No. IPC-E-01-16 were either sent by overnight mail or hand delivered, as indicated below, to the following named parties and addressed as follows:

Lisa D. Nordstrom	____	Hand Delivered
Deputy Attorney General	____	U.S. Mail
Idaho Public Utilities Commission	____	Overnight Mail
472 W. Washington Street	____	FAX
P.O. Box 83720		
Boise, Idaho 83720-0074		
Randall C. Budge	____	Hand Delivered
Racine, Olson, Nye, Budge & Bailey	____	U.S. Mail
Center Plaza-Corner First & Center	____	Overnight Mail
P.O. Box 1391	____	FAX
Pocatello, Idaho 83204-1391		
Anthony Yankel	____	Hand Delivered
29814 Lake Road	____	U.S. Mail
Bay Village, Ohio 44140	____	Overnight Mail
	____	FAX
Peter J. Richardson	____	Hand Delivered
Molly O'Leary	____	U.S. Mail
Richardson & O'Leary	____	Overnight Mail
99 E. State Street, Suite 200	____	FAX
P.O. Box 1849		
Eagle, Idaho 83616		
Stuart Trippel	____	Hand Delivered
Trippel Mast Consulting LLC	____	U.S. Mail
506 Second Avenue, Suite 1001	____	Overnight Mail
Seattle, Washington 98104-2328	____	FAX
Lawrence A. Gollomp	____	Hand Delivered
U.S. Department of Energy, Room 6D-003	____	U.S. Mail
1000 Independence Avenue S.W.	____	Overnight Mail
Washington, D.C. 20585	____	FAX

Dr. Dale Swan Exeter Associates 12510 Prosperity Drive, Suite 350 Silver Springs, Maryland 20904	____ ____ ____ ____	Hand Delivered U.S. Mail Overnight Mail FAX
Conley E. Ward Givens, Pursley LLP 277 North 6th Street, Suite 200 P. O. Box 2720 Boise, Idaho 83701-2720	____ ____ ____ ____	Hand Delivered U.S. Mail Overnight Mail FAX
Ken Tandy Astaris LLC P. O. Box 4111 Highway 30, West of City Pocatello, Idaho 83202	____ ____ ____ ____	Hand Delivered U.S. Mail Overnight Mail FAX

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BARTON L. KLINE

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S INTERIM AND PROSPECTIVE, HEDGING, RESOURCE PLANNING, TRANSACTION PRICING, AND IDACORP ENERGY SERVICES (IES) AGREEMENT	)	CASE NO. IPC-E-01-16

IDAHO POWER COMPANY

REBUTTAL TESTIMONY

OF

TIM J. SIMARD

Q. Please state your name and business address.

A. My name is Tim J. Simard. I am employed by RiskAdvisory. My business address is Suite 610, 1414 8th Street S.W., Calgary, Alberta, Canada T2R 1J6.

Q. What position do you hold with RiskAdvisory?

A. I am a founding Principal of RiskAdvisory.

Q. Please describe your experience relevant to this testimony?

A. I began working with energy companies with respect to the use of risk management instruments and the design of risk management programs in 1986 as an institutional energy futures broker with the Burns Fry Energy Group in Calgary, Alberta. In 1990, I moved to Bankers Trust Canada where I went on to become Vice Chairman with responsibilities for managing Bankers Trust's Canadian energy derivatives operation. RiskAdvisory was created in 1995 and since that time the firm has worked on assignments for over 150 energy companies in the United States, Canada and New Zealand. I have been involved in assignments with 16 electric and natural gas utilities as a member of RiskAdvisory, primarily with respect to the design and implementation of risk management programs. I have served as an expert witness on issues pertaining to the financial management of energy risk in four regulatory hearings for both natural gas and electric utilities.

Q. Have you been retained by Idaho Power Company ("IPC") or its parent IDACORP, Inc. in any other assignments prior to your involvement as an expert witness for these hearings?

A. Yes. I was engaged by IDACORP, Inc. in September 2000 to work with the non-operating group as an Interim Risk Manager. The assignment was to have terminated on December 8, 2000. However, my services were retained on a part-time basis beyond this period until March 1, 2001.

Q. As part of this assignment, what involvement did you have with the utility risk management activity of IPC?

A. My activity was limited to attendance at most of the Risk Management Committee ("RMC") meetings held during the term of my assignment. I listened to the discussions around the risk management issues for the operating function, but did not actively participate in these discussions. My focus was reporting to the Risk Management Committee on those issues pertaining to the risk portfolio of the non-operating trading and marketing activities.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe several key issues that should drive the implementation of a prudent risk management program for a regulated utility. The testimony will also provide an opinion as to the efforts that have been made and continue to be advanced by IPC with respect to its risk management program.

Q. What essential ingredients are required before any entity embarks on a risk management program?

A. The first essential ingredient of a risk management program is the determination of the risk appetite of the individual or group for whom the risk management activity is conducted. Not all participants in a marketplace will have the same appetite for market exposure. A good example is provided by the appetite for different types of residential mortgages. Some homebuyers prefer a mortgage with a fixed interest rate while others opt for an interest rate that floats with underlying movements in short-term interest rates. It is not correct to assume that all market participants want to be insulated against market movements. Many oil and gas companies, for example, choose to retain material exposure to movements in oil and gas prices despite the availability of instruments that can protect them against these movements. While one can assert that all market participants would choose to insulate themselves against risk if this can be done without any potential cost, the recognition that there can be embedded costs in a risk management strategy will change the desirability of that strategy for many participants. A risk management program that could be viewed as prudent for one individual or group may prove to be imprudent for another individual or group based on the risk appetite or risk preference of these market participants.

The second key ingredient in the development of a risk management program is a quantitative assessment of the portfolio of risks faced by the market participant. This quantitative approach allows one to assess the probability of adverse market movements on one’s position. The quantitative model must also allow one to determine the impact that incremental transactions can have on the risk profile of the participant. For complex risk portfolios, it is often not clear as to whether a proposed risk management transaction actually serves to reduce or exacerbate the exposure to market prices.

Equipped with an understanding of the magnitude of market exposures and an assessment of risk appetite, one is in a position to define the underlying objectives of the risk management program, craft policies and procedures associated with any risk management activity and develop the program implementation process.

Q. How should one view the concept of risk appetite within the context of IPC’s regulated environment?

A. It should be understood that any risk management activity undertaken by IPC to manage its PCA balances is primarily on behalf of ratepayers. While there is an incentive component to the PCA structure, the majority of variances in the PCA account flow through to ratepayers. IPC effectively acts as agent for the ratepayers with respect to the implementation of risk management transactions.

Q. What role should ratepayer groups and regulators play in the IPC risk management program?

A. Given that the risk management activity is undertaken primarily on behalf of ratepayers, it is crucial that ratepayer groups and representatives provide their input into any hedging strategy. One should not expect that IPC will be able to determine the optimal strategy without this input. The other factor is that if the ratepayers and their groups are not brought into a collaborative process to determine the nature of the desired risk profile, IPC could be subject to inequitable negative hindsight reviews. If IPC establishes a long hedge position in a particular year without consultation with ratepayers and prices subsequently fall, ratepayers and their representatives could argue after the fact that the hedge was imprudent because ratepayers wanted to retain exposure to falling market prices. Ratepayers should participate in the development of the broad guidelines for risk management and be prepared to accept the consequences of these hedging actions if they lead to a sub-optimal PCA balance.

Q. What role should the market directional views of IPC play in the implementation of the IPC risk management program?

A. Market directional views should not play any role in the implementation of the IPC risk management program. The injection of price views creates a speculative component that is inappropriate for a utility risk management program. The exercise of a price view can lead to instances when “hedges” are established only if one believes the market will move in favor of the hedge position. Ratepayers and regulators should not expect that IPC has any competitive advantage with respect to outforecasting or “beating the market” over the long run. If an exposure is identified and this exposure is unsuitable relative to pre-defined tolerance levels agreed upon between ratepayer groups, the Idaho Public Utilities Commission (“IPUC”) and IPC, the appropriate hedge should be established without regard for IPC’s view on where market prices are likely to move.

Q. Do you agree with the assertion made in the testimony of Staff witness Thomas Lord on page 31 that “One way to assure that Idaho Power regulated customers receive that benefit would be for IES and Idaho Power to adopt a corporate policy that, within the acceptable risk tolerance for regulated customers, IES and Idaho Power would always share congruent market views in the region”?

A. No. IES has been established as a risk-taking entity whose profitability will be a partial function of speculative transactions that are established to capitalize on its speculative perception of future price movements. Positions established on the basis of a price view are not risk-free. As stated above, there is no room for a speculative price view in a defensive risk management program established to protect utility ratepayers against undue volatility in the PCA balance. To reiterate, it would be inappropriate for a proposed risk-reducing transaction to be deferred because of a guess on the part of either IES or IPC about future market direction. Otherwise, ratepayers are taking risk positions based on a speculative element and this should not be the foundation of a defensive risk management program. With the recognition that price speculation should not play a role in the risk management activities of IPC, there will be frequent instances when the defensive hedge positions established by IPC will be in the opposite direction of some of the speculative positions in the IES portfolio.

Q. Should the IPC risk management program be benchmarked on the gains or losses generated by the risk management transactions?

A. No. Gains and losses on the risk management transactions in isolation would only be a benchmarking component if price views influenced the implementation of these positions. Absent the price view component, the gains or losses on the hedge transactions are irrelevant to any prudence review of the hedging activity. The hedge transactions are established to reduce fluctuations to the PCA balance, and are not established to be profitable in isolation.

Q. What are the responsibilities of IPC in the development and implementation of a prudent risk management program?

A. IPC should take responsibility for several elements of the risk management program. First, IPC is in the best position to quantify the risk inherent in the power supply portfolio. IPC should provide the IPUC and ratepayer groups with a thorough understanding of this risk profile and the potential magnitude of adverse PCA balance movements based on current market information. IPC should also provide these stakeholders with an estimate of the benefit and risks associated with several alternative risk management implementation strategies. Equipped with this information, the ratepayer groups and the IPUC will be in a better position to advise IPC on their preferred risk management implementation strategy. The IPUC should also receive periodic reports on the IPC risk position.

As part of the responsibility stated above, IPC should work towards the implementation of a quantitative risk model that takes into account the broad range of varying factors that can affect the PCA balance.

IPC should develop a Policy Manual and a Procedures Manual governing the risk management activity. The Policy will outline the objective of the risk management activity, the responsibilities of various groups within IPC who are involved in the risk management program taking into account the importance of segregation of various duties, any volumetric or dollar risk limits established in conjunction with input from ratepayer groups and the IPUC, an overview of the market risk quantification process, the credit policy with respect to an overview of the quantification of credit risk and the establishment of credit risk limits, and a discussion of the management reporting infrastructure, namely the report contents, the report distribution list (including periodic reports to the IPUC) and the frequency of reports. The Procedures Manual will provide more detail on actual execution procedures to ensure prudent execution and no affiliate abuse and to reduce the operational risks inherent in risk management programs. It will also provide more detail on quantification procedures for both market and credit risk. The detailed involvement of risk monitoring and accounting responsibilities would also form part of the Procedures Manual.

IPC should be responsible for the actual execution of term transactions (which might be brokered by IE or others) and the preparation and distribution of reports.

IPC must have a senior management committee that provides high-level oversight of the risk management program, including the responsibility for interactions with ratepayer groups and the IPUC, and the implementation of the risk management program in line with the strategy prescribed by the ratepayer groups and the IPUC.

Q. Power marketing companies have access to quantitative systems that allow for the daily measurement of risk in their portfolios. Can the risk measurement technology employed by marketing groups be applied directly to the risk position of a utility?

A. No. The risk profiles of electric utilities are materially different from the risk profiles of marketing entities. The first difference lies in the timeframe associated with the risk analysis. Marketing entities are only concerned with the deterioration in the value of their portfolio over a short period of time, typically one day to one month. The marketing approach is based on the principle that if risk limits are violated, the portfolio can be liquidated in a short period of time. On the other hand, utilities are more concerned about the impact to ratepayers on movements over a longer timeframe. In the case of IPC with a one-year PCA period, it is the risk of movements in this PCA balance over the course of the year that need to be quantified. Risk models that allow for price movements over a full year are materially different from a marketing risk system that serves to quantify risk over a much shorter term period.

The second critical difference between modeling utility risk positions and modeling marketing company risk positions centers on the issue of volumetric uncertainty. Marketing companies tend to know with certainty the volumes underlying most of their committed future power market purchases and sales. Most trades are done in standard block transactions where the volumes are contractually fixed. With electric utilities, there can be significant variations around the volumetric availability both on the resource side and on the load side. With respect to the supply from generators, forced outages can lead to sudden drastic reductions in available resources. A host of factors can also cause material variations in load requirements versus expectations. The end result is that one’s forecast surplus/deficit position can change radically as resource availability and load obligations change. This creates significantly more modeling complexity for utilities. Using a marketing company risk model that assumes volumetric certainty can lead to materially inaccurate assessments of risk which in turn can lead to the implementation of risk management transactions that serve to exacerbate risk rather than reduce risk. It would be imprudent for a utility with varying resource availability and load obligations to use a risk management quantification system designed for marketing companies.

Q. Are there facets of the IPC risk profile that make the quantification and management of risk in the portfolio more difficult than for many other electric utilities?

A. Yes. IPC's reliance on unpredictable hydro generation creates even more uncertainty around resource availability than a utility that is less reliant on hydro resources. Exhibit 4 details the variance between forecast IPC monthly generation resources and actual generation for the April 2000 – February 2001 period. The variances can be material: actual generation in January and February 2001 fell almost 30% below the 2000 Integrated Resource Plan ("IRP") forecast, amounting to a shortfall of more than 600 MW for this period. This shortfall represented more than one-third of IPC's combined load and firm sales over these two months.

The high degree of volumetric uncertainty has a significant impact on risk modeling and the risk management decision-making process. As an example, assume that the forecast estimate of available hydro generation in three months' time leads to the conclusion that one will be in a surplus position for this month. Assuming no change in the hydro resource from the forecast (which is the volumetric certainty assumption used in most marketing risk models), one might establish a short forward position in three months to reduce this surplus and return the system to a more balanced position. However, assume in three months' time that actual hydro availability falls well below initial forecast expectations, resulting in a situation where even without the short forward position the system is in deficit. At the same time, market prices have risen. This will result in losses on the "hedge" position even though the hedge was not needed. The establishment of the hedge in this scenario serves to exacerbate the risk of fluctuations in the PCA. Any system or risk management implementation program that is employed which ignores the variability in forecast hydro availability will likely create unfavourable results for ratepayers.

Q. Are risk measurement models available in the marketplace today that can quantify effectively all the volumetric and market-based risks in IPC's portfolio?

A. I am not aware of any comprehensive risk models available in the marketplace today that can assess in an accurate fashion the combined volumetric/price risk embedded in the IPC portfolio.

Q. What efforts has IPC made to develop its risk management program?

A. During the 2000 – 2001 PCA year, the IPC risk position was discussed regularly at the RMC meetings. A report was circulated at each meeting which detailed forecast resources and the net surplus/deficit position by month , along with the impact of the expected forecast and a worst case price/hydro scenario on the PCA balance. This input was used to assess the appropriateness of any risk management strategy. Members of the RMC were fully cognizant of the difficulties associated with establishing hedge positions when there was so much uncertainty around the forecast hydro availability.

In response to the unprecedented degree of market price volatility in the latter half of 2000 and early 2001, IPC has established its own RMC separate from the IDACORP RMC which historically provided oversight to both the operating and non-operating market risk positions. This will ensure a focused review of risk management issues specifically pertaining to the IPC risk position.

IPC has also embarked on a program to

establish a detailed framework for its risk management activities on behalf of ratepayers, including the development of a process to include ratepayer groups and the IPUC in a collaborative approach to the issue of risk management, the mapping of several proposed implementation strategies, a commitment to continue to advance its risk quantification methodologies and the recognition of the need for a Policy Manual and a Procedures Manual to govern the risk management activity of IPC.

The historical recognition on the part of IPC management of the need to manage PCA fluctuations and the initiative to establish a more formal framework for the risk management program should provide the IPUC with comfort surrounding the level of prudence employed by IPC in the area of risk management.

Q. Does IPC currently possess the requisite skills to implement a prudent term risk management program on behalf of its ratepayers?

A. The three key risk functions that are required for the IPC risk management program center around execution capabilities, the risk monitoring and reporting function (“the middle office”) and the senior oversight function. On the execution front, to-date these services have been performed for IPC by the non-operating trading function. Should this relationship continue, the skills certainly exist within the non-operating trading group to execute risk management transactions in an efficient fashion. It should be noted that in a defensive risk management program without a price view component, the execution process becomes a straightforward process where bids or offers are solicited from a number of risk management counterparties over a short period of time and the best price is selected subject to credit risk limits with these counterparties. If the execution of term transactions is transferred to the IPC operating entity, there will be an immediate need to hire a staff member with power market execution expertise, or train a staff member on the basic protocol associated with the execution of term transactions in the regional power market. This would not require an onerous training program. However, this individual should also have the ability to identify other types of risk management transactions that could prove advantageous to ratepayers like option structures, weather derivatives and unit- or hydro-contingent forward market sales. This individual could also assist the Risk Manager and the RMC evaluate recommendations provided by IE under the Electricity Supply Management Services Agreement.

The middle office is responsible for developing the systems and quantification procedures used to track the risk in the IPC portfolio. As I have already discussed, this is a very complex process for IPC. Some of the requisite skills for this position already exist within IPC, most notably with respect to modeling hydro availability. However, this information needs to be consolidated within a broader risk analysis and this will require incremental quantitative modeling skills and systems expertise. This middle office position is normally referred to as the Risk Manager. The Risk Manager could also assist the RMC in evaluating recommendations provided by IE under the Electricity Supply Management Services Agreement.

The Idaho Power RMC would provide the senior management oversight function. From the RMC perspective, most of the members of the IPC RMC committee have served or been observers on the IDACORP RMC. This has resulted in a group that has a good understanding of the use of basic risk management tools and risk quantification methodologies. Ongoing training is required to stay abreast of the latest risk quantification advances and risk management vehicles available in the marketplace, and to ensure a thorough comprehension of the ramifications of any proposed hedge transaction on PCA balances.

Q. How should the IPC risk management program be benchmarked in the future?

A. The performance of IPC with respect to its risk management program should be benchmarked against several factors. First, IPC has a commitment to educate ratepayers and IPUC on the magnitude of risk in the PCA balance, the difficulties associated with estimating this risk, and the types of risk management strategies that can be employed, including the costs, benefits and risks associated with these strategies. IPC should be benchmarked against its ability to communicate these difficult concepts to ratepayers and the IPUC.

IPC should also continue to look for improved methodologies to quantify the risk in its portfolio taking into account the volumetric variability and the price variability. The risk management program can be benchmarked on the effort made by IPC to improve this quantification process.

IPC should prepare best industry practice Policies and Procedures Manuals and part of the benchmarking process should include a review of these manuals.

IPC is responsible for the prudent implementation of the risk management program based on the implementation framework agreed to by ratepayers and the IPUC. If this framework includes volume limits and PCA variance limits, IPC can be benchmarked against its ability to remain within the stated risk tolerances of its stakeholders. If limits are violated, the onus would be on IPC to explain why the limits could not have been defended in a prudent fashion.

Finally, IPC is responsible for ensuring appropriate segregation of duties and to ensure the absence of any affiliate abuse. IPC can be benchmarked against its ability to ensure that these best industry practice standards are met.

Q. Does this conclude your testimony?

A. Yes.

Exhibit 4

	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01
Generation Forecast (MWh)	1,597,680	1,466,424	1,498,320	1,580,256	1,386,816	1,353,600	1,340,688	1,155,600	1,322,832	1,701,528	1,490,496
Actual Generation (MWh)	1,675,382	1,211,760	1,177,995	1,357,008	1,207,981	1,224,788	1,244,552	1,150,200	1,207,899	1,213,677	1,068,343
Difference (MWh)	77,702	(254,664)	(320,325)	(223,248)	(178,835)	(128,812)	(96,136)	(5,400)	(114,933)	(487,851)	(422,153)
Difference (MW)	**108**	**(342)**	**(445)**	**(300)**	**(240)**	**(179)**	**(129)**	**(8)**	**(154)**	**(656)**	**(628)**
Percentage Variance	**5%**	**-17%**	**-21%**	**-14%**	**-13%**	**-10%**	**-7%**	**0%**	**-9%**	**-29%**	**-28%**

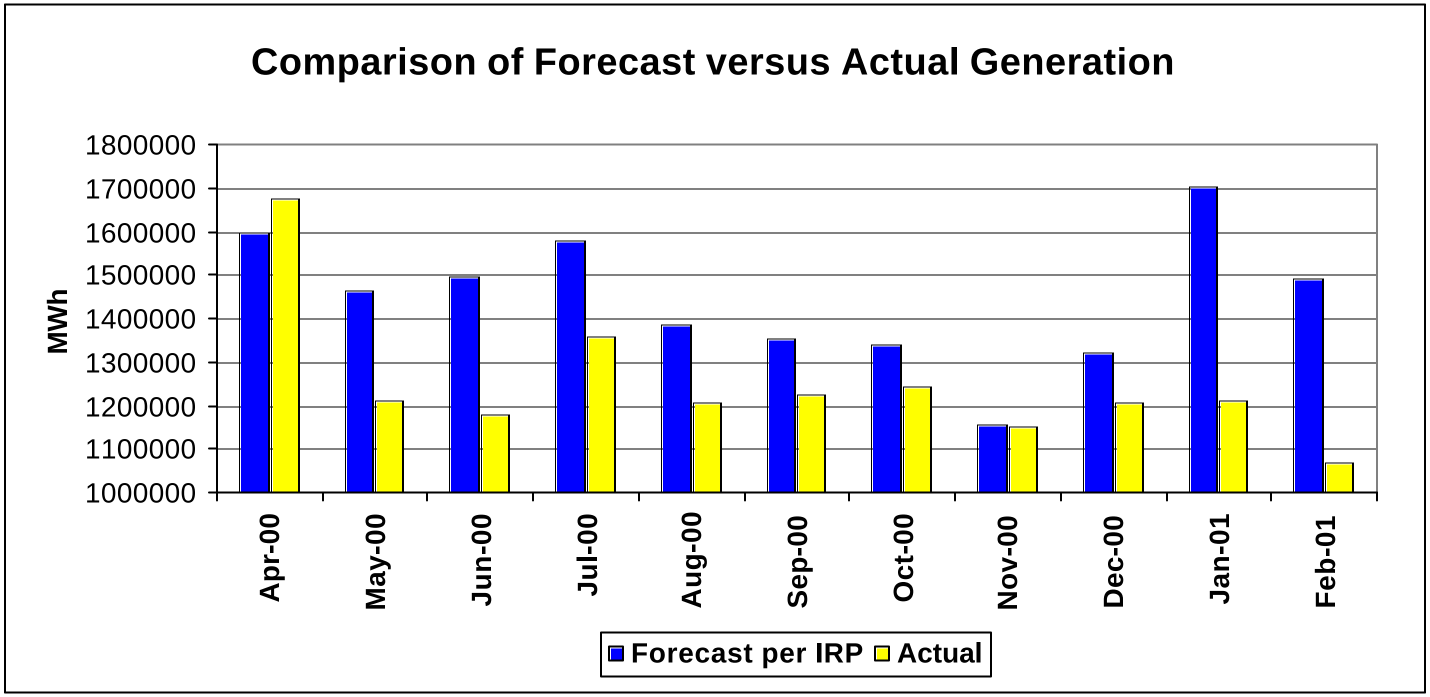

Exhibit No. 4
Case No. IPC-E-01-16
T. Simard, IPCo-Reb
Page 1 of 1

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S INTERIM AND PROSPECTIVE, HEDGING, RESOURCE PLANNING, TRANSACTION PRICING, AND IDACORP ENERGY SERVICES (IES) AGREEMENT	)	CASE NO. IPC-E-01-16

IDAHO POWER COMPANY

REBUTTAL TESTIMONY

OF

JOHN R. GALE

Q. Please state your name and business address.
A. My name is John R. Gale and my business address is 1221 West Idaho Street, Boise, Idaho.
Q. Please state your name and business address.
A. My name is John R. Gale and my business address is 1221 Idaho Street, Boise, Idaho.
Q. By whom are you employed and in what capacity.
A. I am employed by Idaho Power Company as the Vice President of Regulatory Affairs.
Q. Have you previously submitted prefiled direct testimony in this proceeding?
A. Yes.
Q. Please summarize your understanding of Staff witness Lord's testimony related to the issues the Commission identified for investigation in this case.
A. Mr. Lord is concerned with Idaho Power Company's potential over-reliance on the spot market to meet its system needs in the future. He is also concerned with Idaho Power's ability to manage the system on a prospective basis. He specifically mentions the lack of requisite skill sets in the utility along with the lack of appropriate management tools and safeguards. Mr. Lord also discusses additional areas of perceived value that IDACORP Energy

("IE") receives from the arrangement with Idaho Power that may not be compensated under the current terms of the Agreement for Electric Supply Management Services ("the Agreement") between the two entities.

Q. On page 18, line 3 of Mr. Lord's direct testimony, he states that he is unable to determine whether IE charges a brokerage fee for arranging transactions for Idaho Power. Is there a brokerage fee?

A. No, under the agreement between Idaho Power Company and IDACORP Energy, any brokering services are included in the annual fee. That pricing arrangement was explicitly addressed in the Code of Conduct that was filed with this Commission and the Code of Conduct approved by the FERC when it approved the Agreement.

Q. Mr. Lord indicates that the Company may not be taking hedging positions in the future. How do you respond?

A. I cannot find in my direct testimony where this conclusion can be drawn. Nevertheless, so there is no confusion, let me state that Idaho Power Company will take hedging positions in the future when the Idaho Power Risk Management Committee deems it appropriate. It has not been our practice to maintain a completely open position in the past, nor will it be in the future. Neither has it been

Idaho Power's practice to take speculative positions on behalf of the system and its retail customers. Mr. Lord's testimony discussing the problems that could occur if the Company maintains a completely open position is not relevant to Idaho Power's situation.

Q. Does Idaho Power Company have the skill sets to manage the system and the risks associated with it?

A. Yes, the Company has always had and in the future will retain and enhance the requisite skills to manage the system and its risks. Idaho Power Company still retains senior management experienced in power supply and wholesale market issues. The bulk of the information and analytical staff and tools needed to support the Company's planning decisions still resides in the utility. This information includes all customer information and the information associated with customer consumption patterns as well as the software that analyzes load. To enhance the resident skills within Idaho Power with additional risk management expertise, Idaho Power has retained the services of Mr. Tim Simard of RiskAdvisory who is also a Company witness in this case. Mr. Simard describes in his rebuttal testimony some of his initial findings and recommendations concerning Idaho Power's prospective risk management effort. Idaho Power's Internal Audit Manager is also in the process of reviewing and developing recommendations to enhance the formal accounting controls necessary to manage the agreement with IDACORP Energy on behalf of the utility and its customers. The Company's outside auditors, Deloitte & Touche, will review those controls to confirm their efficacy. In addition, Idaho Power continues to have access to the expertise within IDACORP Energy as part of the services provided to the utility under the Agreement between the two entities. The whole discipline of utility risk management has been a rapidly evolving part of the industry. We stand ready to do whatever is needed to be a "best practices" company in this regard.

Q. What is Idaho Power Company doing to better manage its power supply cost risks in the future?

A. As the Commission well knows, Idaho Power's hydroelectric generation has often been a mixed blessing. In the past, low cost has often been confused with low risk. First the seven-year drought and now the "perfect storm" has painfully underscored that the production volume exposure of a hydroelectric utility is high risk, particularly during times of high price volatility. The impact of the extended drought, along with its temporary surcharges, ultimately led to the implementation of the Company's Power Cost Adjustment ("PCA") mechanism. For a number of years prior to the recent price spikes, Idaho Power was able to concentrate on operating its system primarily to optimize its resources by accessing northwest and southwest markets for economy sales and purchases. Some seasonal patterns led to energy exchanges, while some longer-term wholesale contracts gave us the ability to mitigate some of our generating capacity costs. Risk management models for hydro systems were not contemplated until recently because the price volatilities just did not justify their development. Company experience and operating knowledge were the most practical and cost-effective tools during this era.

In the late 1990’s when the trading business began to develop, a new set of skills was added to the experience of the past. While these skills are readily applicable to pure trading activities, they are a work-in-progress for the utility itself. We are sorting through such things as whether it is appropriate for the Company to have a directional price view, what is the risk appetite level for the Company’s customers and Commission, can we establish objective risk management procedures to operate within a specified risk level, and can we develop or obtain a risk model that can address the complexities of a hydroelectric system. The Company will be evaluating the recommendations of Mr. Simard and others to incorporate into its future risk management program. Some of these recommendations have already been adopted, while others may be developed with the assistance of those who have a vested interest in the process. Other recommendations, such as the development of enhanced modeling capability will take some time to implement.

Q. How do you respond to Mr. Lord’s discussion regarding IDACORP Energy’s potential misuse of Idaho Power’s operating information?

A. First I want to emphasize that while Mr. Lord raises some theoretical possibilities, neither Mr. Lord nor anyone else has submitted actual evidence of abuse. Further, as IDACORP Energy’s purchases and sales have grown dramatically over time, they have dwarfed the utility’s comparable purchase and sales – both in terms of volume and dollars. In both dollars and volume, IDACORP Energy’s business with Idaho Power is projected to be less than four percent (4%) of IE’s overall energy business. Nevertheless, perception can be unsettling by itself. Since the actual separation of IDACORP Energy from Idaho Power, both physically and organizationally, the utility has become increasingly more autonomous from its affiliate. The umbrella Risk Management Committee (“RMC”) of the past has been separated into one for Idaho Power and one for IDACORP Energy. The committees are comprised of officers and senior managers of their respective entities. Mr. LaMont Keen, the Chief Financial Officer for the corporation, is the only common member to both committees. Mr. John Prescott, the designated Oversight Manager for Idaho Power is the Chair of the Idaho Power RMC and functions as the supply officer for the Company. Mr. Prescott and the Idaho Power Company RMC are systematically reviewing current market information practices with the assistance of RiskAdvisory. In accordance with the Agreement, IE will make recommendations to the Idaho Power RMC for possible actions to be initiated by Idaho Power. Any appropriate information safeguards will be incorporated into future Company policies and procedures.

Q. Mr. Lord discusses potential value to IDACORP Energy in the Agreement with Idaho Power that has, to date, not been recognized formally in compensation from IDACORP Energy to Idaho Power. What is Idaho Power's view on additional compensation from its affiliate?

A. In the initial Agreement between Idaho Power and IDACORP Energy, mutual cost savings were identified that left the Company's customers in a more favorable position than they would have been without the arrangement. Under the settlement stipulation in Case IPC-E-00-13, $2 million in value flowed through immediately to the Idaho retail customers. Much has evolved since the time that the Commission originally approved the stipulated settlement and accompanying Agreement. The Company has gone through proceedings at the Federal Energy Regulatory Commission and

Oregon Public Utility Commission, the actual separation of IE and Idaho Power has occurred, and we have been engaged in an extended procedure before this Commission. Many parties, including Idaho Power and IE, have considered the potential value in the arrangement. The Company and IDACORP Energy have identified the need to attempt to quantify any additional value that IE could prospectively obtain from the use of system transmission and system capacity services, as well as other potential intangible benefits. At the time this testimony is being prepared, both parties are negotiating a proposed compensation amount that might be applied prospectively for these items. I hope to report on the result of these negotiations at the hearing.

Q. Please summarize your understanding of Staff witness Sterling's testimony related to the issues the Commission identified for investigation in this case.

A. Mr. Sterling discusses some of the difficulties in managing a hydro system during volatile times and the interaction between long-term planning and shorter-term operations. He also makes recommendations regarding the composition and role of Idaho Power Company's Risk Management Committee on a going forward basis.

Q. How do you respond to his comments and recommendations regarding planning and operations?

A. I believe there are substantial areas of agreement between my prefiled direct testimony and Mr. Sterling’s recommendations. The Company agrees that there should be a direct link between planning criteria, the Integrated Resource Plan (“IRP”), and general revenue requirements. If, as a matter of public policy, the Commission determines that the system resource planning should be performed on the basis of a more critical water year or if generating reserve margins need to be increased, the Company can act upon that direction. Again the trade-off will be higher base rates (to reflect the costs of additional capacity) against potentially lower PCA price volatility. I believe the logical time to discuss these issues is during the development of the next IRP. Idaho Power contemplates a significant level of public involvement in the preparation of the 2002 IRP.

Q. Please respond to Mr. Sterling’s comments regarding Idaho Power Company’s Risk Management Committee.

A. I agree with Mr. Sterling’s comments on this issue. As mentioned in Mr. Sterling’s testimony, the Company has established separate Risk Management Committees for both IDACORP Energy and Idaho Power Company. Idaho Power’s RMC is comprised of officers and senior managers from Power Supply, Finance, Delivery, Legal, and Regulatory. As previously mentioned, the only common member to both the

Idaho Power RMC and the IDACORP Energy RMC is Mr. LaMont Keen, the Chief Financial Officer for IDACORP, INC. – the parent company for both companies.

Q. Please summarize your understanding of Staff witness Carlock's testimony related to the issues the Commission identified for investigation in this case.

A. Ms. Carlock states that certain conditions relating to separation, control, information, and compensation need to take place in order for the Staff to once again become comfortable with the IPC/IE arrangement. She recognizes as Mr. Lord did in his testimony, that the "lower-of-cost or market" basis is unsustainable for any period of time for the type of service performed by IDACORP Energy and that Mid-C pricing for intra-month transactions is an "appropriate pricing mechanism once control objectives are quantified and operational".

Q. What is your general response to her testimony related to IPC-E-01-16?

A. I am in general agreement with Ms. Carlock on the desirability of enhancing the existing level of management of the IPC/IE relationship. I do believe that the Company is in the best position to lead on the development of the "best practices" for risk management policy and procedure. The Company is dedicated to enhancing our procedures in this area and welcomes the input of Staff and others in developing an ongoing risk management plan that may be acceptable to all. Initially, the elements of such a plan involve agreement on the role of a price view (or lack thereof) within the utility, some consensus on the risk appetite of the parties, control procedures, information protocols, and the development of a model that can deal with the complexities of a hydroelectric system.

I also agree with Ms. Carlock that the " . . . market pricing for intra-month transactions is appropriate, once control objectives are quantified and operational." I believe that with renewed confidence in the autonomy, controls, value compensation, and risk plan, that the transfer price issue will be behind us.

Q. Witness Carlock testifies on p. 17 that the FERC rejected use of the Mid-C index for setting transfer prices for real-time transactions. What is the status of the Company's real-time pricing methodology at the FERC?

A. First, I must correct a misunderstanding evidenced in Ms. Carlock's testimony on this matter. The FERC did not reject the use of the Mid-C price index for real-time transactions. There is no Mid-C price index for real-time transactions. If there was, I am confident that the FERC would have approved its use for pricing real-time transactions. As noted on page 2 of the April 27, 2001 FERC order (Staff Exhibit No. 118), the FERC found that tying the price of affiliate transactions to a regional market index, which is not subject to manipulation, is an effective mechanism to prevent affiliate abuse.

Because there is no market index for real-time transactions, the FERC directed Idaho Power to amend the Agreement and to revise the tariff and service agreements consistent with Commission precedent governing the sale of power at market-based rates to an affiliated entity. Ms. Carlock correctly notes in her testimony that on May 14, 2001, Idaho Power and IE made a compliance filing in accordance with the FERC's order.

Q. If Idaho Power has made a compliance filing with the FERC, why has it not made a filing with the IPUC to implement that compliance filing?

A. Because the FERC's April 27, 2001 order was rather cryptic on this point, Idaho Power's compliance filing suggests two alternative ways of complying with the FERC's order. In Idaho Power's opinion, both alternatives comply with the FERC's order, but they would have very different effects on transfer pricing for real-time transactions. As of the date of the filing of this testimony, Idaho Power has not received an order from the FERC addressing the May 14, 2001 compliance filing.

Q. Does Idaho Power concur with the FERC's decision regarding real-time pricing?

A. No. In fact, you will note on Page 2 of the FERC Order (Staff Exhibit 118), that after it directed Idaho Power and IE to revise the Agreement with respect to real-time transactions, the FERC order indicates that "Applicants may, in a new Section 205 filing, either; (1) make a showing as to why their real-time pricing proposal is consistent with that precedent; or (2) offer another proposal that is consistent with that precedent." It is Idaho Power's intention to make a new Section 205 filing in the near future. In addition, it is the Company’s intention to meet with the FERC staff personnel familiar with the Agreement in the very near future to discuss the potential adverse impacts on Idaho Power's customers arising out of the FERC's decision to modify the real-time pricing methodology that was acceptable to the parties that signed the Stipulation in the IPC-E-01-13 case.

Q. Please comment on how the fee structure under the IPC-IE Agreement should be evaluated prospectively.

A. I believe the fee structure should continue to provide demonstrated cost savings to the utility. Also, I believe the fees should be able to withstand a market test. The market value should become easier to assess as more of these arrangements are introduced and implemented. It is my understanding that other utilities that serve Idaho customers have risk management agreements with third parties. The Staff could certainly use its audit capabilities to obtain and compare the services and fees under those arrangements against the Idaho Power/IDACORP Energy arrangement. Ultimately it may be determined that service agreements like the IPC/IE Agreement should be put out to bid.

Q. Your testimony describes an evolving, collaborative process through which the Company, the Staff, and the Company's customers develop mutually acceptable revisions and enhancements to the IE/IPC arrangement. Until that process is completed, what are the "ground rules" that should apply to transactions between Idaho Power and IE under the Agreement?

A. It is my belief that there is a strong likelihood that the interested parties will ultimately be able to agree on revised and enhanced controls, practices and compensation that will restore confidence in the IPC/IE arrangement. Achieving that consensus will take some time. During the period when those discussions are being pursued, Idaho Power and IE need to know what the "ground rules", including transfer prices, are. It is not fair to expect that Idaho Power and IE can continue to incur millions of dollars in costs without a reasonable assurance that they will be able to recover those costs so long as they obey the rules which have been accepted by the Commission.

Q. What is your recommendation for the interim rules governing transactions between Idaho Power and IE during the period where the parties are working through the issues on a prospective basis?

A. As indicated in my direct testimony, until such time as the Commission makes a final determination that the existing rules should be changed, Idaho Power believes that the rules governing the conduct of transactions between Idaho Power and IE (including transfer prices) should be the existing rules accepted by this Commission, the FERC and the OPUC. Idaho Power believes this approach is consistent with prior Commission decisions requiring that practices and rules adopted by the Commission remain in effect until changed by subsequent order.

Q. Does that conclude your testimony?

A. Yes.